State of Utah

Department of Environmental Quality

Dianne R. Nielson, Ph.D.
Executive Director

DIVISION OF AIR QUALITY
Richard W. Sprott
Director

OLENE S. WALKER
Governor

GAYLE F. McKEACHNIE
Lieutenant Governor

DAQE-IN0327010-04

April 1, 2004

George W. Cross
Intermountain Power Service Corporation
850 West Brush Wellman Road
Delta, Utah 84624-9522

Dear Mr. Cross:

Re: Intent to Approve: PSD Major Modification to Add New Unit 3 at Intermountain Power Generating Station, Millard County, Utah CDS-A, ATT, NSPS, HAPs, MACT, Title IV, Title V Major. Project Code: N0327-010

The attached document is the Intent to Approve (ITA) for the above-referenced project. ITAs are subject to public review. Any comments received shall be considered before an Approval Order is issued.

Future correspondence on this Intent to Approve should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. Please direct any technical questions you may have on this project to Ms. Milka M. Radulovic. She may be reached at (801) 536-4232.

Sincerely,

Rusty Ruby, Manager
New Source Review Section

RR: MR: jc

cc: Central Utah Public Health Department
Mike Owens, EPA Region VIII

150 North 1950 West • PO Box 144820 • Salt Lake City, UT 84114-4820 • phone (801) 536-4000 • fax (801) 536-4099
T.D.D. (801) 536-4414 • *www.deq.utah.gov*

Utah! Where ideas connect

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

INTENT TO APPROVE: PSD MAJOR MODIFICATION TO ADD NEW UNIT 3 AT INTERMOUNTAIN POWER GENERATING STATION

Prepared By: Milka M. Radulovic, Engineer
(801) 536-4232
Email: milkar@utah.gov

INTENT TO APPROVE NUMBER

DAQE-IN0327010-04

Date: April 1, 2004

Intermountain Power Service Corporation
Source Contact
George Cross
(435) 864-4414

Richard W. Sprott
Executive Secretary
Utah Air Quality Board

Abstract

Intermountain Power Service Corporation (IPSC) currently operates the Intermountain Power Plant (IPP) site located near the town of Delta in Millard County, Utah. The existing plant has two drum-type, pulverized coal (PC)-fired boilers that provide steam to two power-generating units, designated as Unit 1 and Unit 2, each with nominal gross capacity of 950 MW. The Intermountain Power Service Corporation (IPSC) submitted Notice of Intent to expand the IPP facility by adding one additional base load pulverized coal fired electricity generating Unit 3, designed at nominal 950-gross MW (nominal 900-net MW) with dry bottom, tangentially fired or wall-fired boiler and associated equipment. Unit 3 will be equipped with wet flue gas desulphurization (WFGD), selective catalytic reduction (SCR), and baghouses for control of the various emissions.

This project is a major modification for the Prevention of Significant Deterioration (PSD) regulations. On site meteorological monitoring, air dispersion modeling, air quality impacts analysis (including HAPs emissions) including visibility and PSD class I and II impacts analysis, non-attainment boundary impact analysis, and a complete top-down Best Available Control Technology (BACT) review were completed and submitted by the IPSC as a part of their Notice of Intent (NOI). Also, an application for case-by-case maximum achievable control technology (MACT) determinations for hazardous air pollutants (HAPs) was provided as a part of the NOI. Unit 3 is also subject to New Source Performance Standards under 40 Code of Federal Regulations (CFR) 60, Subparts A, Da and Y. Title IV and Title V of the 1990 Clean Air Act apply to this modification and the Title V permit shall be amended prior to the operation of the Unit 3. Unit 3 boiler will be classified Group1, Phase II under the Acid Rain Program. As a result of the performed air quality impacts analysis two auxiliary boiler stack heights will be raised to be no less than 72 feet, as measured from ground level at the base of the stack. The increment analysis indicated that the amount of PM_{10} 24-hour increment consumed by the proposed project would be greater than 50% of the standard; therefore, approval under Utah Administrative Code R307-401-6 (3) from the Utah Air Quality Board would be required. The IPP will meet all primary and secondary National Ambient Air Quality Standards (NAAQS). The IPP will also meet Class I increments in the National Parks in southern Utah and Class II PSD increments in the vicinity of the plant.

The IPP is located in Millard County, an attainment area for all criteria pollutants.

Estimated potential to emit totals from Unit 3, in tons per year, are as follows: PM_{10} 617.15, NO_x 2775, SO_2 3,963.9, CO 5946, VOC 107, HAPs 199.

The Notice of Intent (NOI) for the above-referenced project has been evaluated and has been found to be consistent with the requirements of the Utah Administrative Code Rule 307 (UAC R307). Air pollution producing sources and/or their air control facilities may not be constructed, installed, established, or modified prior to the issuance of an Approval Order (AO) by the Executive Secretary of the Utah Air Quality Board.

A 30-day public comment period will be held in accordance with UAC R307-401-4. A notice of intent to approve will be published in the Millard County Chronicle Progress on April 1, 2004. During the public comment period the proposal and the evaluation of its impact on air quality will be available for both you and the public to review and comment. If anyone so requests a public hearing it will be held in accordance with UAC R307-401-4. The hearing will be held as close as practicable to the location of the source. Any comments received during the public comment period and the hearing will be evaluated.

Please review the proposed AO conditions during this period and make any comments you may have. The proposed conditions of the AO may be changed as a result of the comments received. Unless changed, the AO will be based upon the following conditions:

General Conditions:

1. This Approval Order (AO) applies to the following company:

Site Location	Corporate Office Location
Intermountain Power Service Corporation	Intermountain Power Service Corporation
850 West Brush Wellman Road	850 W. Brush Wellman Road
Delta, UT 84624-9522	Delta, UT 84624

   Phone Number: (435) 864-4414
   Fax Number: (435) 864-6670

   The equipment listed in this AO shall be operated at the following location:

   850 West Brush Wellman Road, Delta, Millard County, Utah

   Universal Transverse Mercator (UTM) Coordinate System: datum NAD27
   4,374.4 kilometers Northing, 364.2 kilometers Easting, Zone 12

2. All definitions, terms, abbreviations, and references used in this AO conform to those used in the Utah Administrative Code (UAC) Rule 307 (R307) and Title 40 of the Code of Federal Regulations (40 CFR). Unless noted otherwise, references cited in these AO conditions refer to those rules.

3. The limits set forth in this AO shall not be exceeded without prior approval in accordance with R307-401.

4. Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved in accordance with R307-401-1.

5. All records referenced in this AO or in applicable NSPS and/or NESHAP and/or MACT standards, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the five-year period prior to the date of the request. Records shall be kept for the following minimum periods:

A.	Used oil consumption	Five years
B.	Emission inventories	Five years from the due date of each emission statement or until the next inventory is due, whichever is longer.
C.	All other records	Five years

6. Intermountain Power Service Corporation (IPSC) shall install and operate the nominal 950 gross-MW power generating Unit 3 with dry-bottom pulverized coal fired boiler and modified equipment associated with Unit 3, as defined by this AO, in accordance with the terms and conditions of this AO, which was written pursuant to IPSC's Notice of Intent submitted to the Division of Air Quality (DAQ) on December 16, 2002 and additional information submitted to the DAQ on May 14, 2003, May 27, 2003, July 28, 2003, September 8, 2003, November 6, 2003, November 7, 2003, November 18, 2003, December 12, 2003, December 18, 2003, January 12, 2004, March 24, 2004, and March 29, 2004.

7. The approved installations shall consist of the following equipment or equivalent*:

A. Unit 3 Dry-bottom Pulverized Coal Fired Boiler for base load operation with Overfire Air Ports System

Maximum Heat Input Rate: 9050×10^6 Btu/hr
Type of Burner: Ultra Low NO_x Burners or equivalent

B. Unit 3 Stack

Stack Height: At least 712 feet, as measured from ground level at the base of the stack.

C. Unit 3 Control Equipment

C.1 Main Boiler Stack Fabric Filter Baghouse

Baghouse Filter Material: Ryton or equivalent

C.2 Wet Limestone Flue Gas Desulfurization System built in redundancy

C.3 Selective Catalytic Reduction System with ammonia injection

D. Two Unit 3 Cooling Towers, 3A and 3B, Equipped with mechanical Mist Eliminators

E. Unit 3 Coal Handling

E.1 Modification of Existing Conveyors: Higher capacity motors on Belts 7 and 8, Belts 9A/9B, 15A/15B expanded to 48"wide;
E.2 New Unit 3 36"wide Conveyors-16A/16B, 17A/17/B, en mass chain totally enclosed conveyors 301A/B, 302A/B, 303, 304, 305, and 306.
E.3 New Coal Transfer Building #5 with Dust Collector EP-127.

E.4 New Coal East Storage Silos 301, 302, 303, 304, and Coal East Storage Silo Bay Dust Collector EP-128.

E.5 New Coal West Storage Silos 305, 306, 307, 308 and Coal West Storage Silo Bay Dust Collector EP-129.

F Unit 3 Fly Ash Handling Equipment: To convey Fly Ash from the fabric filter to the storage silo

F.1 Fly Ash Storage Silo 1C with Loading Spout Vent Dust Collector EP-171

F.2 Fly Ash Storage Silo 1C with Vent Dust Collector EP-172

G Unit 3 Bottom Ash Handling System to convey bottom ash from boiler to storage area.

H. Unit 3 Limestone Handling System for WFGD system

I. Unit 3 WFGD Sludge Handling System

J. Existing Auxiliary Boiler Modification
Installation of an extension on each boiler stack so that each stack height is at least 72 feet, as measured from the ground level at the base of the stack.

K. Unit 3 Water Treatment Plant, Steam System, Turbine generator, and Air heaters**

* Equivalency shall be determined by the Executive Secretary.

** This equipment is listed for informational purposes only. There are no emissions from this equipment.

8. Intermountain Power Service Corporation shall notify the Executive Secretary in writing when the installation of the equipment listed in Condition #7 has been completed and is operational, as an initial compliance inspection is required. To insure proper credit when notifying the Executive Secretary, send your correspondence to the Executive Secretary, attn: Compliance Section.

If construction and/or installation has not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11.

Limitations and Tests Procedures

9. Except for start-up, shut-down, or malfunction, emissions to the atmosphere from the indicated emission point(s) shall not exceed the following rates and concentrations:

Source: Unit 3 Main Boiler Stack		
Pollutant	Emission Rate (lb/MMBtu)	Averaging Period
SO_2	0.12	24-hour block average
SO_2	0.10	30-day rolling average
NO_x	0.07	30-day rolling average
H_2SO_4	0.0044	24*-hour block average
PM_{10} (filterable)	0.015	3-test run average
PM (filterable)	0.020	3-test run average
VOC	0.0027	3- test run average
Fluorides/HF	0.0005	3- test run average
Lead	0.00002	3- test run average

Source: Unit 3 Main Boiler Stack		
Pollutant	Emission Rate (lb/hr)	Averaging Period
PM_{10} (filt.+condensable)	221	24*-hour block average
CO	1357.5	30-day rolling average
NO_x	633.5	24-hour block average
CO	3000	8-hour block average
HCL	38.13	3-test run average

*Based on a 24-hour test run or any method approved by the Executive Secretary, which will provide 24-hour data.

24-hour block means the period of time between 12:01a.m. and 12:00 midnight.
8-hour block average means eight consecutive hours

10. Stack testing to show compliance with the emission limitations stated in the above condition shall be performed as specified below:

A.

Emissions Point	Pollutant	Testing Status	Test Frequency
Unit 3 Main Boiler Stack	PM_{10} (f)/PM_{10} (f+c)	Initial	Annual
	PM (f)	Initial	60-months**
	SO_2	Initial	CEM
	NO_x	Initial	CEM
	CO	Initial	CEM*
	H_2SO_4	Initial	Annual
	VOC	Initial	Annual
	Fluorides/HF	Initial	60-months
	Lead	Initial	60-months
	HCl	Initial	60-months

*or may use CEM equivalent, such as parametric monitoring that may be approved by the Executive Secretary
**or parametric monitoring that may be approved by the Executive Secretary

B. Testing Status (To be applied to the source listed above)

Initial: Initial compliance testing is required. The initial test date shall be performed as soon as possible and in no case later than 180 days after the start up of a new emission source, an existing source without an AO, or the granting of an AO to an existing emission source that has not had an initial compliance test performed. If an existing source is modified, a compliance test is required on the modified emission point that has an emission rate limit.

Annual: Test every year. The Executive Secretary may require testing at any time.

60-months: Test every five years. The Executive Secretary may require testing at any time.

CEM: After the initial test compliance shall be demonstrated through use of a Continuous Emissions Monitoring System (CEMs) as outlined in Condition #21 below. The Executive Secretary may require testing at any time.

C. Notification

The Executive Secretary shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Executive Secretary.

The source test protocol shall be approved by the Executive Secretary prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, stack to be tested, and procedures to be used. A pretest conference shall be held, if directed by the Executive Secretary.

D. Sample Location

The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by the Executive Secretary. An Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approved access shall be provided to the test location.

E. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2 or other testing methods approved by the Executive Secretary.

F. PM/PM_{10}

For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201, 201A, or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the method specified by the Executive Secretary. All particulate captured shall be considered PM_{10}, for PM_{10} (filt+condensable) limit.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists (or for PM determination), then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5A, 5B, or 5D, or as appropriate, or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the Method 202 or other as approved by the Executive Secretary. The portion of the front half of the catch considered PM_{10} shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Executive Secretary.

The back half condensibles shall not be used for compliance demonstration for PM (filterable) limit and shall be used for inventory purposes.

G. Sulfur Dioxide (SO_2)

40 CFR 60, Appendix A, Method 6, 6A, 6B, 6C, or other testing methods approved by the Executive Secretary.

H. Nitrogen Oxides (NO_x)

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, 7E, or other testing methods approved by the Executive Secretary.

I. Sulfuric Acid Mist (H_2SO_4)

40 CFR 60, Appendix A, Method 8, or other testing methods approved by the Executive Secretary.

J. Carbon Monoxide (CO)

40 CFR 60, Appendix A, Method 10, or other testing methods approved by the Executive Secretary.

K. Volatile Organic Compounds (VOCs)

40 CFR 60, Appendix A, Method 25 or 25A

L. Hydrogen chloride (HCl)

40 CFR 60, Appendix A, Method 26 or 26A

M. Fluorides/Hydrogen fluoride (HF-hydrofluoric acid)

40 CFR 60, Appendix A, Method 26 or 26A

N. Lead

40 CFR 60, Appendix A, Method 12

O. Calculations for Testing Results

To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary, to give the results in the specified units of the emission limitation.

P. New Source Operation

For a new source/emission point, the production rate during all compliance testing shall be no less than 90% of the production rate listed in this AO. If the maximum AO allowable production rate has not been achieved at the time of the test, the following procedure shall be followed:

1. Testing shall be at no less than 90% of the production rate achieved to date.

2. If the test is passed, the new maximum allowable production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate.

3. The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum AO production rate is achieved.

Q. Existing Source Operation

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years.

11. Except for start-up, shut-down, planned/maintenance outage, or malfunction, differential pressure range at all times at the indicated points shall not exceed the following values

Unit 3 Dust Collectors

Source	differential pressure range across the dust collector (inches of water gage)
Fly Ash Storage Silo 1C Loading Spout Vent (EP-171)	0.5 to 12*
Fly Ash Storage Silo 1D Vent (EP-172)	0.5 to 12*
Coal Transfers Building #5 Vent (EP-127)	0.5 to 12*
Coal East Storage Silo Bay (EP-128)	0.5 to 12*
Coal West Storage Silo Bay (EP-129)	0.5 to 12*

*If differential pressure is less than 2 inches or greater than 10 inches, work orders will be written to investigate. Dust collector may run in the 0.5 to 2 or 10 to 12 range if reason is known. Intermittent recording of the reading is required on a monthly basis.

The instrument shall be calibrated against a primary standard annually. Preventive maintenance shall be done quarterly on each baghouse.

12. Initial emission testing for mercury (Hg) is required within 180 days of commencing operation. Testing shall be performed using the following methods.

Emission	Testing Method*	Rate
Mercury (Hg)	40 CFR 60, Appendix A, Method 29	6.0 x 10^{-6} lb/MWhr

* or other testing methods approved by the Executive Secretary

The mercury content of any coal burned in Unit 3 shall be monitored and recorded based on "as-fired" monthly composite. Certification of fuels shall be either by IPSC's own testing or test reports from the fuel marketer. For determining mercury content in coal, American Society for Testing and Materials (ASTM) Method D3684-01 or other method approved by the Executive Secretary, is to be used.

.

If the initial emission testing for mercury is passed, the source can operate using coal with mercury content no greater than 110% of the tested mercury content without further testing. If the monthly composite analyses indicate mercury values greater than 110% of the initial emission test, IPSC shall immediately arrange a new emission test for mercury at the higher mercury value within 60 days. Upon verification of compliance with mercury limit, new coal with a mercury content value no greater than of 110% of the last tested value shall then be allowed without further emission testing. No such emission testing is required if IPSC installs and operates a continuous mercury emissions analyzer.

13. Visible emissions from the following emission points shall not exceed the following values:

A. All baghouses at dust collectors' exhausts- 10% opacity
B. All other points - 20% opacity covered under this AO

Opacity observations of emissions from stationary sources shall be conducted according to 40 CFR 60, Appendix A, Method 9. Visible emissions from mobile sources and intermittent sources shall use procedures similar to Method 9

For sources that are subject to NSPS, opacity standards shall be determined by conducting observations in accordance with 40 CFR 60.11(b) and 40 CFR 60, Appendix A, Method 9.

14. IPSC shall abide by a boiler manufacturer written instruction and/or written procedure developed and maintained by IPSC for the Unit 3 main boiler startup, shutdown, and malfunction periods.

15. The following Unit 3 boiler production and/or consumption limits shall not be exceeded:

A. 9050 million British Thermal Units (MMBtu) per hour full load heat input rate for Unit 3 boiler, using Higher Heating Value HHV of the fuel.
B. 3,541,248 tons of coal burned per rolling 12-month period

Consumption shall be determined by the main boiler control system database. The records of consumption shall be kept on a daily basis.

Roads and Fugitive Dust

16. IPSC shall abide by a fugitive dust control plan acceptable to the Executive Secretary for control of all dust sources associated with the addition of Unit 3 at the Intermountain Power Generation site. IPSC shall submit fugitive dust control plan to the Executive Secretary, attention: Compliance Section, for approval within 90 days of the date of this AO. This plan shall contain sufficient controls to prevent an increase in PM_{10} emissions above those modeled for this AO. The limitations and conditions in the fugitive dust control plan shall not be changed.

    Visible fugitive dust emissions from Unit 3 haul-road traffic and mobile equipment in operational areas shall not exceed 20% opacity. Visible emissions determinations for traffic sources shall use procedures similar to Method 9. The normal requirement for observations to be made at 15-second intervals over a six-minute period, however, shall not apply. Six points, distributed along the length of the haul road or in the operational area, shall be chosen by the Executive Secretary or the Executive Secretary's representative. An opacity reading shall be made at each point when a vehicle passes the selected points. Opacity readings shall be made ??? vehicle length or greater behind the vehicle and at approximately 1/? the height of the vehicle or greater. The accumulated six readings shall be averaged for the compliance value.

Fuels

17. The owner/operator shall use either bituminous or blend of bituminous and subbituminous coals as a primary fuel, blended to meet emission performance standards. The owner/operator shall use fuel oil during the startups, shutdowns, maintenance, upsets conditions and flame stabilization in the Unit 3 9050 x 10^6 Btu/hr boiler. The owner/operator may blend self-generated used oil with coal at the active coal pile reclaim structure providing record that self-generated used oil has not been mixed with hazardous waste.

18. The sulfur content of any fuel oil burned shall not exceed:

    0.85 lb per 10^6 Btu heat input for fuel used in the Unit 3 9050 x 10^6 Btu/hr boiler

    The sulfur content of fuel oil shall be determined by ASTM Method D-4294-89 or approved equivalent. Certification of fuel oil shall either be by IPSC's own testing or test reports from the fuel oil marketer.

Federal Limitations and Requirements

19. In addition to the requirements of this AO, all applicable provisions of 40 CFR 60, New Source Performance Standards (NSPS) Subpart A, 40 CFR 60.1 to 60.18, Subpart Da, 40 CFR 60.40a to 60.49a (Standards of Performance for Electric Utility Steam Generating Units for Which Construction in Commenced After September 18, 1978), Y, 40 CFR 60.250 to 60.254 (Standards of Performance for Coal Preparation Plants), and 40 CFR 64 (Compliance Assurance Monitoring for Major Stationary Sources) apply to this installation.

20. In addition to the requirements of this AO, all applicable provisions of 40 CFR Part 72, 73, 75, 76, 77, and 78 - Federal regulations for the Acid Rain Program under Clean Air Act Title IV apply to this installation.

Monitoring - General Process

21. The owner/operator shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMs) on the main boilers stacks and SO_2 removal scrubbers inlets. The owner/operator shall record the output of the system, for measuring the opacity, SO_2, CO, and NO_x emissions. The monitoring system shall comply with all applicable sections of R307-170, UAC; and 40 CFR 60, Appendix B.

    All continuous emissions monitoring devices as required in federal regulations and state rules shall be installed and operational prior to placing the affected source in operation.

    Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring devices and shall meet minimum frequency of operation requirements as outlined in 40 CFR 60.13 and Section UAC R307-170.

Records & Miscellaneous

22. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this Approval Order including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded.

23. The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring.

24. The owner/operator shall comply with R307-107. General Requirements: Unavoidable Breakdowns.

The Executive Secretary shall be notified in writing if the company is sold or changes its name.

Under R307-150-1, the Executive Secretary may require a source to submit an emission inventory for any full or partial year on reasonable notice.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307.

A copy of the rules, regulations and/or attachments addressed in this AO may be obtained by contacting the Division of Air Quality. The Utah Administrative Code R307 rules used by DAQ, the Notice of Intent (NOI) guide, and other air quality documents and forms may also be obtained on the Internet at the following web site: http://www.airquality.utah.gov/

The annual emissions estimations below are for the purpose of determining the applicability of Prevention of Significant Deterioration, non-attainment area, maintenance area, and Title V source requirements of the R307. They are not to be used for determining compliance.

The Potential To Emit (PTE) emissions for the entire Unit 3 operations are currently calculated at the following values:

	Pollutant	Tons/yr
A.	PM_{10} (filterable)	617.15
B.	SO_2	3,963.9
C.	NO_x	2775
D.	CO	5946
E.	VOC	107
F.	H_2SO_4	174
G.	Lead	0.79
H.	Total Reduced Sulfur	29
I.	Reduced Sulfur Compounds	29
J.	HAPs	
	Mercury	0.024
	Hydrochloric Acid (HCL)	167.01
	Fluorides/HF	20
	Total HAPs	199

The Division of Air Quality is authorized to charge a fee for reimbursement of the actual costs incurred in the issuance of an AO. An invoice will follow upon issuance of the final Approval Order.

Sincerely,

Rusty Ruby, Manager
New Source Review Section